AMENDMENTS TO THE CLAIMS

1 (Original). A method for analyzing distributed temperature data from a well, comprising:

obtaining temperature profile data along a portion of a wellbore;

providing the temperature profile data to a processor; and

automatically processing the temperature profile data to highlight valuable information to a user.

2 (Original). The method as recited in claim 1, wherein automatically processing comprises removing noise from the temperature profile data.

3 (Original). The method as recited in claim 1, wherein automatically processing comprises removing low order spatial trends.

4 (Original). The method as recited in claim 1, wherein automatically processing comprises utilizing a high-pass filter.

5 (Original). The method as recited in claim 1, wherein automatically processing comprises utilizing a low-pass filter.

6 (Original). The method as recited in claim 1, wherein automatically processing comprises applying a model-fitting algorithm to the data.

7 (Original). The method as recited in claim 6, wherein applying a model-fitting algorithm comprises selecting regions for fitting and fitting a model to data.

8 (Original). The method as recited in claim 7, wherein applying a model-fitting algorithm further comprises testing results for statistical significance.

9 (Original). The method as recited in claim 6, wherein applying a model-fitting algorithm comprises constructing a match filter and using extrema of a convolution of the filter with data to select candidate depths.

10 (Original). The method as recited in claim 9, wherein constructing a match filter comprises incorporating modifications to the filter to make it orthogonal to background trends.

11 (Original). The method as recited in claim 1, wherein automatically processing comprises trend removal and filtering of the temperature profile data.

12 (Original). The method as recited in claim 1, wherein obtaining comprises utilizing a distributed temperature sensor.

13 (Original). The method as recited in claim 1, wherein obtaining comprises deploying an optical fiber in the wellbore.

14 (Original). The method as recited in claim 1, wherein obtaining comprises obtaining the temperature profile data with a temporary distributed temperature sensor installation.

15 (Original). The method as recited in claim 1, wherein obtaining comprises obtaining the temperature profile data with a slickline distributed temperature sensing system.

16 (Original). The method as recited in claim 1, wherein automatically processing comprises utilizing a match filter.

17 (Original). The method as recited in claim 16, wherein the match filter is used to detect particular temperature signals corresponding to a particular downhole event.

18 (Original). The method as recited in claim 17, wherein the downhole event comprises the location of a gas lift valve.

19 (Original). The method as recited in claim 17, wherein the downhole event comprises a hole in a tubing.

20 (Original). The method as recited in claim 17, wherein the downhole event comprises a leak in a wellbore completion tool.

21 (Original). The method as recited in claim 1, wherein the automatically processing occurs in real-time with the obtaining data.

22 (Original). A system to analyze distributed temperature data from a well, comprising:

a distributed temperature sensor adapted to measure temperature profile data along a portion of a wellbore;

a processor adapted to receive the temperature profile data; and

wherein the processor automatically processes the temperature profile data to highlight valuable information to a user.

23 (Original). The system as recited in claim 22, wherein the distributed temperature system comprises an optical fiber.

24 (Original). The system as recited in claim 22, wherein the distributed temperature sensor comprises an opto-electronic unit to launch optical pulses downhole.

25 (Original). The system as recited in claim 24, wherein the opto-electronic unit is coupled to the processor by a communication link.

26 (Original). The system as recited in claim 25, wherein the communication link comprises a hardline link.

27 (Original). The system as recited in claim 25, wherein the communication link comprises a wireless link.

28 (Original). The system as recited in claim 22, wherein the processor is embodied in a portable computer.

29 (Original). The system as recited in claim 23, further comprising a production tubing deployed in the wellbore with the optical fiber.

30 (Original). The system as recited in claim 29, wherein the production tubing is combined with a gas lift system.

31 (Original). A method of detecting certain events within a well, comprising:

obtaining data over a period of time along a portion of a wellbore;

automatically processing the data to detect specific events related to heat energy in the well; and

displaying results to a user.

32 (Original). The method as recited in claim 31, wherein obtaining data comprises obtaining temperature data along the portion of the wellbore.

33 (Original). The method as recited in claim 32, wherein obtaining temperature data comprises utilizing a distributed temperature sensor.

34 (Original). The method as recited in claim 31, wherein automatically processing comprises processing the data on a processor-based computer.

35 (Original). The method as recited in claim 31, wherein automatically processing comprises processing backscattered light signals.

36 (Original). The method as recited in claim 31, wherein automatically processing comprises applying a model-fitting algorithm to the data.

37 (Original). The method as recited in claim 36, wherein applying a model-fitting algorithm comprises selecting regions for fitting and fitting a model to data.

38 (Original). The method as recited in claim 37, wherein applying a model-fitting algorithm further comprises testing results for statistical significance.

39 (Original). The method as recited in claim 36, wherein applying a model-fitting algorithm comprises constructing a match filter and using extrema of a convolution of the filter with data to select candidate depths.

40 (Original). The method as recited in claim 39, wherein constructing a match filter comprises incorporating modifications to the filter to make it orthogonal to background trends.

41 (Original). The method as recited in claim 31, wherein automatically processing comprises applying a phenomenological model to the data.

42 (Original). The method as recited in claim 31, wherein automatically processing comprises detecting particular temperature signals corresponding to a particular downhole event.

43 (Original). The method as recited in claim 31, wherein automatically processing comprises detecting particular temperature signals corresponding to location of a gas lift valve.

44 (Original). The method as recited in claim 31, wherein automatically processing comprises detecting particular temperature signals corresponding to a wellbore completion tool leak.

45 (Original). The method as recited in claim 31, wherein automatically processing comprises detecting particular temperature signals corresponding to a hole in a production tubing.

46 (Original). The method as recited in claim 31, wherein displaying comprises displaying results in graphical form on a display monitor.

47 (Original). The method as recited in claim 31, wherein automatically processing comprises utilizing a match filter.

48 (Original). The method as recited in claim 31, wherein automatically processing occurs real-time with the obtaining data.

49 (Withdrawn). A method of determining a flow rate, comprising:

providing a well model relating temperature characteristics to a flow rate of a production fluid in a well having a gas lift system;

measuring temperatures along the well; and

determining the flow rate based on applying the well model to measured temperature data.

50 (Withdrawn). The method is recited in claim 49, wherein determining comprises determining the flow rate based on a decay length of a thermal perturbation at a gas injection location.

51 (Withdrawn). The method as recited in claim 49, wherein determining comprises determining the flow rate based on a measured amplitude of a thermal discontinuity at a gas injection location.

52 (Withdrawn). The method as recited in claim 49, further comprising estimating the heat capacity of the production fluid and using the heat capacity estimate in the well model.

53 (Withdrawn). A method, comprising:

measuring a temperature profile in a well having a gas lift system to produce a fluid through a production tubing; and

determining a flow rate through the production tubing based solely on the temperature profile and established well parameters.

54 (Withdrawn). The method as recited in claim 53, further comprising obtaining the established well parameters.

55 (Withdrawn). The method as recited in claim 54, wherein obtaining comprises establishing a heat capacity of the fluid.

56 (Withdrawn). The method as recited in claim 54, wherein obtaining comprises establishing a radial heat transport value in the well.

57 (Withdrawn). The method as recited in claim 54, wherein obtaining comprises establishing a thermal conductivity of a surrounding well formation.

58 (Withdrawn). The method as recited in claim 54, wherein obtaining comprises establishing a thermal history of the well.

59 (Withdrawn). The method as recited in claim 53, wherein measuring comprises measuring the temperature profile with a distributed temperature sensor.

60 (Withdrawn). The method as recited in claim 53, wherein determining comprises determining the flow rate based on a decay length of a thermal perturbation at a gas injection location.

61 (Withdrawn). The method as recited in claim 53, wherein determining comprises determining the flow rate based on a measured amplitude of a thermal discontinuity at a gas injection location.

62 (Withdrawn). The method as recited in claim 53, further comprising processing the temperature profile according to a stored model relating the temperature profile to the flow rate.

63 (Withdrawn). A method of determining a flow rate, comprising:

providing a well model relating flow rate of a production fluid to a decay length of a thermal perturbation at a gas injection location;

measuring temperatures along the well; and

applying the well model to the measured temperatures to determine the flow rate based on the decay length of the thermal perturbation.

64 (Withdrawn). The method as recited in claim 63, wherein providing comprises developing the well model to utilize a heat capacity of the production fluid.

65 (Withdrawn). The method as recited in claim 63, wherein providing comprises developing the well model to utilize a radial heat transport value of the well.

66 (Withdrawn). The method as recited in claim 63, wherein providing comprises developing the well model to utilize a thermal conductivity of a surrounding formation.

67 (Withdrawn). The method as recited in claim 63, wherein providing comprises developing the well model to utilize a thermal history of the well.

68 (Withdrawn). A method of determining a flow rate, comprising:

providing a well model relating flow rate of a production fluid to a measured amplitude of a thermal perturbation at a gas injection location;

measuring temperatures along the well; and

applying the well model to the measured temperatures to determine the flow rate based on the measured amplitude of the thermal perturbation.

69 (Withdrawn). The method as recited in claim 68, wherein providing comprises developing the well model to utilize a heat capacity of the production fluid.

70 (Withdrawn). The method as recited in claim 68, wherein providing comprises developing the well model to utilize a pressure drop between an annulus and a production tubing.

71 (Withdrawn). The method as recited in claim 68, wherein measuring comprises utilizing a distributed temperature sensor.

72 (Withdrawn). The method as recited in claim 68, wherein applying comprises applying the well model to the measured temperatures on a processor system.

73 (Withdrawn). A system, comprising:

a temperature sensor system deployed with a gas lift system in a well to measure temperature in a plurality of locations along the well; and

a processor system able to receive the measured temperatures and apply the measured temperatures to a stored model, the stored model being able to establish a fluid flow rate of a produced fluid based on a thermal perturbation at a gas injection location of the gas lift system.

74 (Withdrawn). The system as recited in claim 73, wherein the temperature sensor system comprises a distributed temperature sensor.

75 (Withdrawn). The system as recited in claim 73, wherein the stored model establishes the fluid flow rate based on a decay length of the thermal perturbation.

76 (Withdrawn). The system as recited in claim 73, wherein the stored model establishes the fluid flow rate based on a measured amplitude of the thermal perturbation.

77 (Withdrawn). The system as recited in claim 73, wherein the well model utilizes an established well parameter to improve the accuracy of the determined fluid flow rate for a given well.

78 (Withdrawn). The system as recited in claim 77, wherein the established well parameter comprises a heat capacity of the produced fluid.

79 (Withdrawn). The system as recited in claim 77, wherein the established well parameter comprises a radial heat transport value of the well.

80 (Withdrawn). The system as recited in claim 77, wherein the established well parameter comprises a thermal conductivity of a surrounding formation.

81 (Withdrawn). The system as recited in claim 77, wherein the established well parameter comprises a thermal history of the well.

82 (Withdrawn). A system, comprising:

means for measuring a temperature profile in a well having a gas lift system to produce a fluid through a production tubing; and

means for determining a flow rate through the production tubing based solely on the temperature profile and established well parameters.

83 (Withdrawn). The system as recited in claim 82, wherein the means for measuring comprises a distributed temperature sensor.

84 (Withdrawn). The system as recited in claim 82, wherein the means for determining comprises a model relating a thermal perturbation to a flow rate of the fluid.

85 (Withdrawn). A method of determining a flow rate, comprising:

providing a well model relating temperature characteristics to a flow rate of a production fluid in a well;

measuring temperatures along the well; and

determining the flow rate based on applying the well model to measured temperature data.

86 (Withdrawn). A method, comprising:

measuring a temperature profile in a well having a gas lift system to produce a fluid through a production tubing;

determining a flow rate through the production tubing based on the temperature profile and established well parameters; and

automatically optimizing the flow rate.

87 (Withdrawn). The method as recited in claim 86, wherein measuring comprises measuring the temperature profile with a distributed temperature sensor.

88 (Withdrawn). The method as recited in claim 86, wherein automatically optimizing comprises changing a gas injection rate.

89 (Withdrawn). The method as recited in claim 86, wherein determining comprises determining the flow rate based on a decay length of a thermal perturbation at a gas injection location.

90 (Withdrawn). The method as recited in claim 86, wherein determining comprises determining the flow rate based on a measured amplitude of a thermal discontinuity at a gas injection location.

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91 (Withdrawn). A system, comprising:

a distributed temperature sensor deployed with a gas lift system in a well to obtain a temperature profile along the well; and

a processor system able to receive the measured temperatures and apply the measured temperatures to a stored model, the stored model being able to establish a fluid flow rate of a produced fluid and to automatically optimize the fluid flow rate.

92 (Withdrawn). The system as recited in claim 91, wherein the stored model establishes the fluid flow rate based on a decay length of a thermal perturbation along the gas lift system.

93 (Withdrawn). The system as recited in claim 91, wherein the stored model establishes the fluid flow rate based on a measured amplitude of a thermal perturbation along the gas lift system.

94 (Withdrawn). The system as recited in claim 91, further comprising utilizing an established well parameter to improve the accuracy of the fluid flow rate determined for a given well.